IN THE UNITED STATES DISTRICT COURT
FOR THE NORTHERN DISTRICT OF TEXAS
DALLAS DIVISION

EXXON MOBIL CORPORATION,	§	
	§	
Plaintiff,	§	
	§	
v.	§	Civil Action No. 3:00-CV-0815-M
	§	
UNITED STATES OF AMERICA,	§	
	§	
Defendant.	§	

FINDINGS OF FACT AND CONCLUSIONS OF LAW

This case was tried from July 8, 2002 - July 16, 2002, and argued on July 25, 2002. Having heard and considered the evidence and the arguments of counsel, the Court makes these Proposed Findings of Fact and Conclusions of Law:

FINDINGS OF FACT

1. This is an action brought under Internal Revenue Code ("Code") sections 6532 and 7422[1] for the refund of federal income taxes (plus interest) that Exxon Corporation ("Exxon")[2] paid for the tax year ending December 31, 1976. The issue is the proper determination of Exxon's depletion deduction with respect to natural gas it produced from 442 properties in East Texas and along the Texas Gulf Coast, and sold after processing or transportation under twenty long-term contracts. This suit is one of many filed by Exxon in

[1] All references to the Internal Revenue Code (26 U.S.C.) and Treasury Regulations (26 C.F.R.) are to the versions in effect for the taxable year 1976, unless stated otherwise.

[2] On November 30, 1999, Exxon Corporation merged with Mobil Corporation. This case concerns the activities of Exxon Corporation, Exxon Company, U.S.A., and its predecessor, Humble Oil & Refining Company. The entity now known as ExxonMobil, and all of the predecessor entities, will be collectively referred to herein as "Exxon."

which it challenges the treatment by the Internal Revenue Service of its percentage depletion deduction. The first year litigated by Exxon was 1974. *See Exxon Corporation v. United States*, 33 Fed. Cl. 250 (1995), *rev'd*, 88 F.3d 968 (Fed. Cir. 1996) ("Exxon I"). Exxon also litigated 1975 in the Court of Federal Claims. *See Exxon Corporation v. United States*, 45 Fed. Cl. 581, *aff'd in part and rev'd in part*, 244 F.3d 1341 (Fed. Cir. 2001) ("Exxon II"). Exxon filed suit for its 1979 tax year in the United States Tax Court. *See Exxon Corporation v. Commissioner*, 102 T.C. 721 (1994). The 1980-90 tax years are docketed in the Tax Court. After this suit was tried, Exxon filed suit over 1977 and 1978 in this Court.

2. One of the principal issues in this case, as in *Exxon I* and *Exxon II*, is the determination of Exxon's "gross income from the property" under Code section 613 for each of the 442 properties. Gross income from the property is defined principally by regulation. Treas. Reg. § 1.613-3(a) provides that if "gas is not sold on the premises but is manufactured or converted into a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price [the "RMFP"] of the . . . gas before conversion or transportation." Exxon sold the gas produced from the 442 properties after transporting it off the premises and, in most cases, after it was processed, thus requiring the calculation of an RMFP to compute Exxon's depletable gross income from the property.

3. In *Exxon I*, the Federal Circuit held "that the RMFP of gas is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." *Exxon I*, 88 F.3d at 976; *see also Exxon II*, 244 F.3d at 1344, quoting, with approval, the RMFP definition in *Exxon I*.

4. Code section 613A, effective for tax years beginning after December 31, 1974, limited Exxon's depletion deduction to natural gas "sold under a fixed contract." Plaintiff's claim must accordingly be limited to the gas from the 442 properties sold under "fixed contracts." The parties have stipulated that eighteen of the twenty contracts in issue were "fixed contracts." *See* JX11.[3] Defendant contests whether the remaining two contracts, with Houston Lighting & Power Company ("HL&P") and Southwestern Electric Power Company ("SWEPCO"), qualify as "fixed contracts" for purposes of Code section 613A. For whatever number of contracts this Court determines are fixed (eighteen, nineteen, or twenty), this Court must determine the RMFP.

5. Exxon is a New Jersey corporation now headquartered in Irving, Texas.

6. On September 15, 1977, Exxon timely filed with the Internal Revenue Service Center (Manhattan District) in New York, New York, a consolidated federal income tax return for the 1976 taxable year.

7. On its 1976 return, Exxon claimed percentage depletion deductions totaling $69,846,305 with respect to the 442 properties at issue. JX12 ¶ 8. Exxon calculated its "gross income from the property" for the gas sold from the properties using its 1976 "Exxon Field Price" of approximately $1.05/Mcf, which was based on average prices calculated from pipeline company purchases of both raw and processed gas, as reported to the State of Texas. PX72 at 30-32 and at Ex. 20. The 1976 Exxon Field Price lagged behind the market price because gas

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[3] "JX" refers to Joint Exhibits. "PX" refers to Plaintiff's Exhibits. Exhibits (or Appendices) to Plaintiff's various expert witness reports are referred to by a citation in the form, "PX at Ex. (or App.) ___." The citations to testimony or exhibits are included merely to assist in a review of the trial transcript. They are not a comprehensive listing of all supporting evidence in the record.

prices were rising rapidly and the purchaser data Exxon used to calculate the Field Price was not available from the State of Texas on a current basis. PX 72 at 31-32 and at Ex. 20.

8. The Commissioner of Internal Revenue ("Commissioner") audited Exxon's 1976 tax return and assessed deficiencies and interest, based in part on a $63,275,367 reduction in the $69,846,305 in percentage depletion deductions claimed for the 442 properties. The Commissioner disallowed all of Exxon's percentage depletion deductions for gas sold to certain of Exxon's industrial and utility customers. JX12 ¶ 10.

9. Exxon paid the $30,372,176 tax deficiency resulting from the Commissioner's disallowance of $63,275,367 of Exxon's percentage depletion deductions, plus interest, for 1976 and, on June 5, 1990, timely filed with the Internal Revenue Service Center at Holtsville, New York, a claim for refund of $121,426,851 in tax, plus interest. Of that sum, $41,855,880 was attributable to percentage depletion deductions for natural gas sold under fixed contracts. JX1 ¶ 1; JX12 ¶ 11.

10. On January 8, 1992, Exxon filed with the Internal Revenue Service Center at Holtsville, New York, an additional claim for refund of $523,935,903 in tax, plus interest, for its 1976 tax year. This refund claim included an additional $23,136,355 of tax attributable to additional percentage depletion deductions and $13,116,000 of tax attributable to a claim for deductions with respect to well-plugging, removal, and restoration costs associated with offshore oil and gas platforms. JX1 ¶ 2.

11. Both of Exxon's claims for refund satisfied the requirements of Code section 6511(c). The claims were neither allowed nor disallowed prior to April 8, 2000, when Exxon filed this action. JX1 ¶ 3.

12. With respect to the portion of Exxon's January 8, 1992 refund claim relating to costs associated with offshore oil and gas platforms, the parties have agreed that Exxon should be allowed a deduction of $123,039 for 1976, which results in an overpayment of tax of $59,056.[4] JX2 ¶ 2.

13. In 1976, as today, Exxon's principal business was exploring for and producing crude oil and natural gas, as well as refining, transporting, buying, and selling oil and gas and the products that can be made from them. JX3 ¶ 2; *Exxon II*, 45 Fed. Cl. at 588; *Exxon I*, 33 Fed. Cl. at 251-52.

14. During 1976 and prior years, natural gas producers typically sold their gas production in the field to intrastate and interstate pipeline companies, which then transported the gas and sold it to end-users and local distribution companies. Because of the magnitude of its reserves in the 1930s, Exxon built its own gas pipeline system, which was known as the Exxon Gas System ("EGS"). JX3 ¶ 3; PX72 at 27; *Exxon II*, 45 Fed. Cl. at 589; *Exxon I*, 33 Fed. Cl. at 262.

15. Just as it was in 1974 and 1975, in 1976, EGS was a 1,500-mile intrastate pipeline system with two primary, interconnected lines – one running from a point near Corpus Christi in South Texas to a point near Tyler in Northeast Texas, and the other running from Houston to Port Arthur. JX3 at ¶ 4; *Exxon II*, 45 Fed. Cl. at 589. EGS brought gas production from Exxon's large natural gas reserves in East Texas and along the Texas Gulf Coast to customers in the increasingly industrialized markets of the Houston-Beaumont area.

[4] The parties have further agreed that after these Findings and Conclusions are issued, they will attempt to stipulate to the amount of overpayment of assessed interest due Exxon.

16. To guarantee a market for its gas that would justify the large capital investment in EGS, in the 1950s and 1960s, Exxon entered into a number of long-term, fixed-price gas sales contracts with industrial and utility customers along the Texas Gulf Coast and in East Texas. Exxon called these contracts its Texas Industrial Commitment ("TIC") contracts. This case involves Exxon's entitlement to, and/or calculation of, percentage depletion for natural gas sold under sixteen of these TIC contracts, as well as four long-term contracts for sales of natural gas to pipeline companies at the tailgates of Exxon's gas processing plants. JX3 ¶ 6; PX72 at 1, 27, 29 and at Ex. 17.

17. In 1976, EGS and Exxon's TIC customers were supplied with gas from 442 properties in more than 75 oil and gas fields in the Texas Gulf Coast/East Texas area; approximately 85% of the total EGS gas came from three fields: King Ranch, Pledger, and Katy. JX3 ¶ 5; PX 72 at 29-30, 35. The reserves in these three fields were among the largest on the Texas Gulf Coast. Included within the 442 properties at issue are properties that produced gas which did not directly supply EGS.

18. During 1976, Exxon owned an economic interest, within the meaning of Treas. Reg. § 1.611-1(b), in each of the 442 properties at issue, and 99% of the gas Exxon sold under the twenty contracts was from Exxon's working interest share of the gas produced from the 442 properties. JX12 ¶ 2; PX72 at 29. The remaining 1% was gas that Exxon purchased from other working-interest owners in the 442 properties or in adjacent properties. PX72 at 29. Each of the properties at issue is a "property" within the meaning of I.R.C. § 614 and Treas. Reg. § 1.611-1(d)(1). JX12, ¶¶ 2-3.

19. Approximately 90% of the gas entering EGS in 1976 was transported to Exxon's

TIC customers. PX72 at 27-28.

20. The gas sold to non-TIC customers under fixed contracts was not transported through EGS, but rather was delivered to the buyers at the tailgates of Exxon's gas processing plants. JX3 ¶ 6; PX72 at 27 and at Ex. 17.

21. Natural gas is found in hydrocarbon accumulations in geologic traps called reservoirs. Natural gas exists in three conditions in reservoirs: (1) gas, without the presence of oil; (2) gas dissolved in oil; and (3) a gas cap over oil. JX3 ¶ 8; PX72 at 6; *Exxon I*, 33 Fed. Cl. at 256.

22. Although the term "field" is used in a variety of contexts in the oil and gas industry, in general the term "field" refers to a localized geographic area overlaying a single reservoir or multiple reservoirs in relatively close proximity. JX3 ¶ 9; PX72 at 9.

23. The terms "basin" and "embayment" are used to describe large geographic areas containing many fields and hundreds of reservoirs. These terms generally describe the contours of ancient seabeds that provided multiple traps and resulted in hydrocarbon accumulations in a particular geographic area. Map 1 referred to in the Map Stipulation, JX3, shows the embayments and basins, in Texas and surrounding areas in 1976. JX3 ¶ 10.

24. When produced, natural gas is generally classified as "gas well gas" or "casinghead gas," depending on its origin. Gas well gas typically refers to both gas that is found in a gaseous state at reservoir conditions (*i.e.*, in its natural state underground), and to gas produced from a well classified as a gas well. Casinghead gas refers to gas that is dissolved in oil at reservoir conditions but becomes gaseous at atmospheric pressure at the top, or "casinghead," of an oil well, and all gas produced from a well classified as an oil well, including

gas from the gas cap of oil reservoirs that is gaseous at reservoir conditions. JX3 ¶¶ 8, 11; PX72 at 6; *Exxon I*, 33 Fed. Cl. at 256.

25. Natural gas is composed primarily of methane with small amounts of heavier hydrocarbons such as ethane, propane, butane, and pentane. Methane, the lightest hydrocarbon component of natural gas, has one carbon atom. Ethane, the second lightest, has two carbon atoms. Propane and butane have three and four carbon atoms, respectively; the hydrocarbon components of natural gas with five or more carbon atoms (pentane, hexane, heptane, octane, nonnane, and decane) are generally referred to collectively as "natural gasoline." JX3 ¶ 12; PX72 at 7; *Exxon II*, 45 Fed. Cl. at 589; *Exxon I*, 33 Fed. Cl. at 256.

26. Natural gas as it emerges from the wellhead is part of a mixture of hydrocarbon gases and liquids with trace quantities of nonhydrocarbon constituents, such as nitrogen, hydrogen sulfide, carbon dioxide, helium, and water. This entire combination is known as the "full wellstream," and the nonhydrocarbon constituents of the full wellstream are commonly referred to as "impurities." Natural gas containing a significant amount of hydrogen sulfide is generally referred to as "sour gas." Natural gas that is relatively free of sulfur constituents is called "sweet gas." JX3 ¶¶ 16-17; PX72 at 9; *Exxon I*, 33 Fed. Cl. at 256-57. Virtually all (99.8%) of the Exxon gas in this case is sweet gas. JX3 ¶ 17; PX72 at 9.

27. Because the full wellstream contains a mixture of minerals and contaminants in solid, liquid, and gaseous phases, it cannot be accurately measured or commercially sold. JX3 ¶ 18; PX72 at 13; *Exxon I*, 33 Fed. Cl. at 256-57. Accordingly, in most cases, the full wellstream is "separated" by the producer. Separation is a mechanical process relying on gravity and filters that divides the full wellstream into the "raw gas" that rises to the top of the separator, water and

sediment that sink to the bottom, and oil and condensate that come to rest in the middle. JX3 ¶ 19; PX72 at 13-14; *Exxon I*, 33 Fed. Cl. at 257.

28. Raw gas is occasionally sold after separation. However, most gas produced along the Texas Gulf Coast and in East Texas must first be "dehydrated" to meet the water vapor specification of most gas purchase contracts. Dehydration is accomplished by running the raw gas stream through a vertical cylindrical vessel, in which the gas rises through "trays" containing triethylene glycol. The glycol absorbs the water vapor and falls to the bottom of the vessel, where it is drained. This procedure removes enough of the water vapor to meet the typical pipeline specification of no more than seven pounds of water per million cubic feet of gas. JX3 ¶ 20; PX72 at 14; *Exxon I*, 33 Fed. Cl. at 257.

29. After dehydration, gas produced in the Texas Gulf Coast/East Texas areas usually met the quality specifications of most gas purchase contracts, and was thus considered "pipeline quality gas." However, most contracts also contain a pressure specification (maximum delivery pressure) designed to ensure that the gas is at a high enough pressure to enter the purchaser's pipeline. Most gas wells initially produce at a sufficiently high pressure (flowing tubing pressure, or "FTP") to meet the specification and enter a pipeline. As gas in a reservoir is depleted, however, its FTP may fall below the pressure specification. If a pipeline company is unable or unwilling to make accommodating reductions in the pressure in its pipeline, the gas must be compressed to continue to flow into the pipeline. JX3 ¶ 22; PX72 at 11, 15.

30. When a lease is first developed, a producer usually puts its field facilities (*i.e.*, the separator, dehydrator, compressor and other equipment needed to bring gas up to pipeline specifications) near the first production well or wells. As it drills more wells, the producer may

exploit economies of scale by installing flow lines to connect new wells to existing field facilities. PX72 at 16.

31. After dehydration, raw gas is transported via gathering lines to either gas plants for processing, or transmission lines for delivery to end users. Gas processing involves the removal or separation of liquefiable hydrocarbons (ethane, propane, butane, and natural gas) from raw gas. This is done using temperature differentials and/or lean oil contact (absorption). This process does not change the molecular structure of the components of the raw gas stream, but it does cause the heavier hydrocarbons to change phase from gas to liquids. The portion of the raw gas stream that remains gaseous (principally the methane) is known as "processed" (or "residue") gas. JX3 ¶ 22; PX72 at 18-19; *Exxon I*, 33 Fed. Cl. at 257-58. Exxon processed most of the gas at issue in this case at nine of its own gas plants located at the King Ranch, Anahuac, Lovell Lake, East Texas, Hawkins, Katy, Pledger, Tom O'Connor, and Clear Lake Fields, along the Texas Gulf Coast and in East Texas. PX72 at 20 and at Ex. 10.

32. The various hydrocarbon components of natural gas can be burned to produce heat. The amount of heat produced is measured in British Thermal Units ("Btus"). One Btu is the amount of heat needed to raise one pound of water from 39 to 40 degrees Fahrenheit. JX3 ¶ 13; JX72 at 8; *Exxon I*, 33 Fed. Cl. at 258. As a rule, the higher the percentage of heavier hydrocarbon components in the gas, the greater its Btu content. JX3 ¶ 14; PX72 at 8; *Exxon I*, 33 Fed. Cl. at 258. The heating value (*i.e.*, the Btu content) of one Mcf of natural gas at a standard temperature and pressure is typically 1 to 1.2 million Btus (MMBtus). JX3 ¶ 14; PX72 at 8. It is generally easier to measure natural gas volume (Mcfs) than heating content (MMBtu), so historically gas was most commonly measured in Mcfs. Because natural gas is sold for its

heating content, however, MMBtu is a more accurate measure of its value, and by the early 1970s, natural gas was commonly priced on a Btu basis. JX3 ¶ 15; PX72 at 8, 23. All but one of the Exxon TIC contracts in this case contain pricing terms based on Btu content. By 1978 the Natural Gas Policy Act mandated that the maximum lawful price of natural gas be a Btu price. PX72 at 23.

33. Under Btu pricing, the price per Btu of natural gas is the same regardless of the Btu content of the gas. Indeed, in 1976, pipeline purchasers did not pay a premium above the Btu value for high Btu content gas, even though in theory such gas could be processed at a gas plant to remove more liquefiable hydrocarbons than could be removed from low Btu content gas. PX72 at 23-24.

34. The heavier hydrocarbons, once liquefied and removed from raw gas, are used by chemical plants and refineries to manufacture plastics and other products, or are sold as more easily transportable specialty fuels (like propane or butane). JX3 ¶ 23; PX72 ¶ 19; *Exxon I*, 33 Fed. Cl. at 258.

35. Gas from gas fields or gas plants is delivered to gas users and consumers via a vast network of gas transmission lines or pipelines (with associated compressor stations). Typically, a pipeline system begins with small diameter lines, also known as "gathering lines," that collect gas from individual wells or common points in a field. These gathering lines converge into larger diameter "lateral lines" which, in turn, converge into large diameter main "transmission lines." The process reverses itself at delivery points, with large diameter transmission lines giving way to smaller diameter lateral lines, and lateral lines feeding into small diameter service lines running to industrial and residential consumers. PX72 at 25.

36. Since 1938, the Federal Power Commission (the "FPC") and its successor, the Federal Energy Regulatory Commission (the "FERC"), have regulated the transportation of natural gas across state lines. From 1954 until 1993, this jurisdiction also included the regulation of the price of gas sold to interstate pipeline companies. JX3 ¶ 26; PX72 at 25-26. The FPC did not regulate the production, transportation, and sale of intrastate gas until December 1978, when the Natural Gas Policy Act became law. JX3 ¶ 27; PX72 at 26.

37. In 1976, a significant number of pipelines ran along the Texas Gulf Coast because some of the largest deposits of natural gas in the United States are found in that area. These pipelines were principally intrastate pipelines that had been built to serve the heavy, local demand for gas in the Texas Gulf Coast/East Texas area, which was the most heavily populated industrial area of Texas and the largest gas consuming area in the State. PX72 at 26; PX74 at 5. The pipeline corridor along the Texas Gulf Coast is sometimes referred to as "pipeline alley." PX72 at 26; Testimony of R.F. Pohler. By contrast, the West Texas area (*i.e.,* the Permian Basin) was dominated by large, interstate pipelines, connecting that area to California and the upper Midwest. Likewise, pipelines in the Texas Panhandle were primarily interstate systems, serving the Midwest and Northeast United States. PX72 at 26; PX74 at 5; Testimony of R.F. Pohler.

38. In 1976, natural gas pipelines were not required to offer to transport natural gas for a fee and, therefore, operated "closed" systems. PX79 at 5; Testimony of R.F. Pohler. Accordingly, a producer's market for its natural gas production in 1976 was limited to pipeline companies with a physical pipeline system that could connect to the producer's wells. PX72 at 27; PX79 at 4; Testimony of R.F. Pohler and J.E. Ellis. For the Exxon properties in issue, this area was the Texas Gulf Coast and East Texas. Testimony of R.F. Pohler and J.E. Ellis. It was

not until late 1984, when the FERC implemented a policy requiring open access transportation on interstate pipelines, that an "open" system existed. PX79 at 5.

39. From at least the end of the Second World War until the late 1960s, there was a surplus of natural gas in the United States. The FPC, while directly controlling only the price of gas sold in interstate commerce, effectively controlled the price of all gas because intrastate pipelines could buy sufficient supplies merely by offering to meet the interstate price. PX74 at 5-6.

40. One result of low, steady prices was that gas pipelines were able to buy and sell gas through long-term, fixed-price contracts. PX72 at 29; Testimony of W.T. Slick, F.M. Perkins, and M.G. Whitcomb.

41. Keeping the price of gas low through regulation increased demand and discouraged drilling. In the late 1960s and early 1970s, gas production began to outstrip additions to gas reserves and the first signs of a demand imbalance in the industry appeared. Testimony of W.T. Slick, D.D. Jordan, F.M. Perkins. *See Exxon I*, 33 Fed. Cl. at 259-60. Nationwide gas reserves, which in 1950 were enough to meet 30 years of expected demand, had fallen by 1975 to only 11.6 years of expected demand. PX79 at 8. Total gas production delivered to transmission lines in Texas (approximately 3.6 trillion cubic feet (Tcf) in 1954) peaked at 7.4 Tcf in 1972, declined to 6.3 Tcf in 1975, and continued to decline for the rest of the decade, despite an increase in the number of gas wells in Texas during this same period. *Id.*

42. In the early 1970s, an increase in demand, caused by rising prices of alternative energy sources and industrial and residential expansion, ran directly into declining supply, with the result that unregulated intrastate prices began to increase dramatically. PX74 at 6; Testimony

of W.T. Slick and D.D. Jordan; *Exxon I*, 33 Fed. Cl. at 260. Because the maximum legal price set by the FPC for gas purchased by interstate pipelines was far below market in 1976, as it had been in 1974 and 1975, intrastate pipeline companies continued to outbid interstate pipelines for new supplies. PX74 at 6; s*ee Exxon I*, 33 Fed. Cl. at 260. The interstate pipelines could generally contract for new gas reserves only where the reserves: (1) were too remote to be economically connected to an intrastate system; (2) were under acreage already dedicated to interstate production; or (3) were on the Outer Continental Shelf beneath the Gulf of Mexico, which federal law required to be sold in the interstate market. PX74 at 6-7.

43. Competition for new supplies of gas was as intense in 1976 as it had been in 1974 and 1975. Interstate pipelines routinely offered the highest price permitted by regulation, but were generally outbid by intrastate purchasers. Intrastate pipelines competed aggressively for new supplies throughout the Texas Gulf Coast/East Texas area, establishing higher and higher prices. Testimony of J.C. Buie.

44. Increasing gas prices in the late 1960s and early 1970s spurred a rapid move away from long-term, fixed-price contracts in the intrastate part of the market as old contracts expired and new wells were drilled. By the early 1970s, the industry developed new standard long-term contracts that had periodic price redetermination clauses. These clauses allowed a producer to adjust periodically the price of his gas to meet the highest price or prices paid within a defined area. Testimony of F.M. Perkins; *Exxon I*, 33 Fed. Cl. at 260.

45. The result of the shift toward Btu pricing and the use of price redetermination clauses – when combined with the large number of aggressively competing pipelines – meant that prices under contemporaneous contracts, or contemporaneously redetermined intrastate

prices, were generally about the same throughout the Texas Gulf Coast/East Texas market area. *See Exxon I*, 33 Fed. Cl. at 260.

46. Congress has permitted a portion of a natural gas producer's income to be reduced by a deduction for the depletion of its reserves before being taxed. *Commissioner v. Engle*, 464 U.S. 206, 208-09 (1984). Because a gas producer never knows for certain how much gas is in its wells, the proportionate loss of its reserves must be estimated. I.R.C. § 611(a) therefore provides for a "reasonable allowance" for depletion "according to the peculiar conditions in each case."

47. Taxpayers were permitted to deduct the greater of cost (I.R.C. § 612) or percentage (I.R.C. § 613) depletion. Under cost depletion, a taxpayer amortizes the actual cost of the well over its total productive life. Under percentage depletion, a taxpayer may deduct a statutorily specified percentage of the gross income generated from the property, irrespective of the actual costs incurred.

48. Integrated producers like Exxon receive income for the products they sell after the raw gas they produce has been processed and transported. Nonintegrated producers, in contrast, sell their gas before it is processed and transported. To maintain parity between integrated and nonintegrated producers for tax purposes, it was clear that integrated companies like Exxon, which added value to raw gas before selling it, should not be permitted to compute their "gross income from the property" using that added value. *Hugoton Production Company v. United States*, 315 F.2d 868, 869 (Ct.Cl. 1963)("*Hugoton I*"); *Exxon II*, 45 Fed. Cl. at 592.

49. To calculate what an integrated producer's gross income for depletion purposes would be, Treasury Regulation § 1.613-3 defined "gross income from the property" to mean "the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well." If a

company did not in fact sell gas at the wellhead, then the regulation provided that "gross income from the property" was "assumed to be equivalent to the representative market or field price [RMFP] of the oil or gas before conversion or transportation."

50. Dramatic developments in the mid-1970s "brought about an abrupt redirection in the nation's energy policy," which ultimately led to the repeal of percentage depletion for most large gas producers. *Engle*, 464 U.S. at 211. This repeal was effective January 1, 1975, and was applicable to tax years ending after December 31, 1974. In 1976, therefore, Exxon was no longer entitled to claim percentage depletion for all sales of its raw gas.

51. The repeal of percentage depletion, however, came with a few exceptions, one of which applied to some of Exxon's natural gas sales. Although prices for energy products were generally increasing rapidly, many companies had entered into long-term fixed-price contracts for the sale of gas and the increase in gas prices did not generally impact those contracts. Therefore, percentage depletion was still allowed for sales of natural gas made pursuant to "fixed contracts." I.R.C. § 613A(b)(1)(B). It is undisputed that Exxon sold natural gas in 1976 under "fixed contracts" within the meaning of Section 613A(b)(3)(A).

52. Exxon sold the gas produced from the 442 properties after transporting it off the premises and, in most cases, after it was processed.

53. Subject to certain limitations, a taxpayer's percentage depletion is computed by multiplying a taxpayer's "gross income from the property," excluding an amount equal to any rents or royalties paid or incurred by the taxpayer in respect of the property, by 22 percent. The amount resulting from this computation becomes a deduction from the taxpayer's gross income from the sale of natural gas. The percentage depletion deduction is also subject to a limitation of

50 percent of the taxpayer's "taxable income from the property (computed without regard to allowance for depletion)" (the "taxable income limitation"). Treas. Reg. §§ 1.613-1(a), 1.613-5(a). A taxpayer's "taxable income from the property" is generally equal to the taxpayer's "gross income from the property," less certain expenses and deductions. *Id.*

54. The total volume of gas sold by Exxon under the twenty contracts at issue during 1976 was 686,905,907 Mcf. Excluding the HL&P and SWEPCO contracts, the total volume of gas sold by Exxon under the eighteen remaining contracts at issue during 1976 was 395,687,529 Mcf. Accordingly, the HL&P and SWEPCO contracts account for 43% of the gas at issue in this case. The total income generated by Exxon under the twenty contracts at issue during 1976 was $211,563,388. Excluding the HL&P and SWEPCO contracts, the total income generated by Exxon under the remaining eighteen contracts at issue during 1976 was $86,876,062. Accordingly, the HL&P and SWEPCO contracts account for 59% of the actual gross income Exxon earned from the twenty contracts at issue.

55. The RMFP "is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." *Exxon II*, 45 Fed. Cl. at 592-93, quoting *Exxon I* at 976. The RMFP, therefore, has three distinct elements: (i) the qualification of the comparable sales of gas as "wellhead sales," (ii) the comparability of gas produced in the relevant market area to the taxpayer's gas, and (iii) the relevant market area. *Id.*

56. The parties stipulated that all of the natural gas transactions used by Exxon and by the United States in their respective proposed RMFPs were "wellhead sales." JX 9. The parties also stipulated that each of the parties' proposed RMFPs was based on gas that was comparable to the natural gas sold by Exxon. JX 8. Exxon contended at trial that despite the United States's

use of wellhead sales of comparable gas in its proposed RMFP calculations, the United States's proposed RMFPs were not appropriate RMFPs to the extent they were: (1) limited to transactions involving fixed-price contracts; (2) included sales outside of the area in which Exxon produced the gas in issue (the relevant market area); or (3) were more heavily weighted toward lower-priced, interstate transactions than was appropriate for the larger areas argued for by the United States. The United States contended, partly in the alternative, that: (1) the RMFP should be calculated solely on the basis of fixed-price transactions; (2) the applicable market area should be broader than the area from which Exxon produced the gas in issue; and (3) that its RMFP samples were representative of the broader market areas.

57. The RMFP calculated by Plaintiff's expert, Mr. Ellis, is based on the volume-weighted average price of East Texas and Texas Gulf Coast producer sales of raw gas comparable to the Exxon gas in issue. PX79 at 1, 15; Testimony of J.E. Ellis.

58. The method established by prior decisions for determining an RMFP requires the development of information from the annual reports and contract files of the natural gas pipelines in the market area and the use of the annual report volumes and values for the qualified transactions. PX79 at 1; Testimony of J.E. Ellis. In this case, wellhead sales transactions were identified by the parties, and sales prices were adjusted for values added by the producer in the form of dehydration or compression. JX9.

59. The courts in both *Exxon I* and *Exxon II* found that the relevant market area for RMFP purposes was the area in which Exxon's gas at issue was produced. Specifically, the Court of Federal Claims in *Exxon II* determined that the relevant market area for 1975 was "the Texas Gulf Coast/East Texas region, consisting of Texas Railroad Commission Districts 2

through 6, inclusive." *Exxon II*, 45 Fed. Cl. at 620.

60. As in *Exxon II*, Exxon's gas at issue in this case is produced in a contiguous area in Texas represented by RRC Districts 2 – 6. PX72 at 33; PX77 ¶ 9; and PX79 at 11; Testimony of R.F. Pohler and J.E. Ellis. The location of Exxon's properties within RRC Districts 2 – 6 did not change meaningfully between 1975 and 1976 and there were no material changes in the number or extent of pipelines that purchased gas from producers in the area. PX74 at 2; PX79 at 2; and PX80 at 3; Testimony of R.F. Pohler and J.E. Ellis. As in 1975, virtually all of the natural gas produced in RRC Districts 2 – 6 in 1976 was sold to pipelines in that area. PX80 at 2; Testimony of R.F. Pohler and J.E. Ellis. Consequently, there were no material factual changes between 1975 and 1976 that would indicate any difference in the relevant market area. PX72 at 33; PX79 at 11; Testimony of R.F. Pohler and J.E. Ellis.

61. Natural gas is transported almost exclusively through pipelines, and the market for gas from a particular property is determined by the presence of pipelines with economical access to that property. PX74 at 8; PX79 at 4; Testimony of R.F. Pohler, J.C. Buie, and J.E. Ellis; *Exxon I*, 33 Fed. Cl. at 260.

62. Because of the heavy concentration of pipelines in the Texas Gulf Coast/East Texas area, these pipelines competed for the purchase of Texas Gulf Coast/East Texas gas production as it came onto the market in 1976. PX74 at 16; PX77 ¶ 29; PX79 at 10; Testimony of J.L. Sweeney, J.C. Buie, and J.E. Ellis. *See also Exxon II,* 45 Fed. Cl. at 608; *Exxon I*, 33 Fed. Cl. at 259. As a practical matter, producers in that area in 1976 had one market for their gas: the Texas Gulf Coast/East Texas pipelines located near the producers' wells. Pipelines in West Texas had no access to purchase Texas Gulf Coast/East Texas production and so could not, and

did not, purchase such production. *See* PX74 at 15; PX79 at 4; PX7 ¶ 31; Testimony of R.F. Pohler, and J.E. Ellis; *see Exxon I*, 33 Fed. Cl. at 260. Because of these circumstances, the price for new gas in 1976 was essentially the same throughout the entire region of the Texas Gulf Coast/East Texas. PX77 ¶ 29; Testimony of J.L. Sweeney.

63. Those pipelines with connections between the Texas Gulf Coast/East Texas and West Texas bought gas in West Texas and transported it to the Texas Gulf Coast/East Texas area for sale. The converse was not true. West Texas pipelines did not purchase gas from Texas Gulf Coast/East Texas producers, because there was more than enough gas in West Texas to satisfy West Texas demand. West Texas was thus not a market for gas produced in East Texas and along the Texas Gulf Coast. PX74 at 16; PX77 ¶¶ 31-32; PX79 at 7; Testimony of J.L. Sweeney and J.E. Ellis. As the court found in *Exxon II*, "the pipelines connecting West Texas with the Texas Gulf Coast were flowing gas from west to east, not east to west." Thus, "the notion that Texas Gulf Coast/East Texas gas producers stood in the posture of immediate competitors to Permian Basin gas producers . . . is patently fallacious." *Exxon II*, 45 Fed. Cl. at 619.

64. There were no significant structural changes in the pipeline networks serving Exxon's production area between 1975 and 1976. With minor exceptions, pipelines purchased gas from the same RRC Districts in 1976 as in 1975. As a result, natural gas producers with reserves located in RRC Districts 2 – 6 had similar access to markets in 1976 as they did in 1975, and Exxon's market access in 1976 remained limited by the physical location and capacity of the pipelines in its production area. PX79 at 12; Testimony of J.E. Ellis.

65. The court in *Exxon II* determined that the relevant market area for RMFP purposes should be, as nearly as possible, "geographically coterminous" with the area from which the

taxpayer produced the gas at issue. *Exxon II*, 45 Fed. Cl. at 615; PX77 ¶ 14; Testimony of J.L. Sweeney. As the court noted in *Exxon II,* the geographic market area should "equalize the taxpayer to his surroundings, *i.e.*, the physical area in which his *immediate* competitors find themselves." *Exxon II*, 45 Fed. Cl. at 615-16 (emphasis in original), quoting *Hugoton Production Co. v. United States*, 349 F.2d 418, 431; *see also* PX77 ¶ 14; Testimony of J.L. Sweeney.

66. At the immediate locality of the taxpayer's gas production, if the gas is physically the same, the market price will be identical to that of the taxpayer's gas. PX78 ¶ 16; Testimony of J.L. Sweeney; *Exxon II*, 45 Fed. Cl. at 615-16. If good approximations of prices of comparable gas at these geographically close locations can be obtained, then the objective of determining the geographic scope of the relevant market area has been accomplished and the inquiry ends there. PX77 ¶ 13; PX78 ¶ 18; Testimony of J.L. Sweeney; *Exxon II*, 45 Fed. Cl. at 616.

67. A price redetermination clause in a contract for the sale of natural gas generally allows the producer to redetermine periodically its contract price on the basis of the average of the highest prices being paid in a specified area. PX79 at 10-11; Testimony of J.E. Ellis. These clauses typically reference the immediate area that includes the producer's wells, most often defined in terms of a RRC District. Sometimes the referenced area will extend to two or three RRC Districts or even more. PX80 at 2; Testimony of J.L. Sweeney and J. E. Ellis.

68. The predominant practice in 1976 was to allow a redetermination of price based on prices geographically near the field or fields at issue. This indicates that the relevant market area is co-extensive with the production area. PX78 ¶¶ 16-17; Testimony of J.L. Sweeney.

69. The most common price redetermination provisions in evidence in this case are limited to references to other sales in the same RRC District. A subset of these provisions imposed specific county or field limitations, which limited reference prices to other sales in areas smaller than a single district. PX80 at 6.

70. Taken as a whole, the price redetermination clauses for RRC District 2 - 6 sales confirm the contemporaneous belief of market participants that the market area was tied to the production area and did not extend to West Texas. PX79 at 10-11; Testimony of J.E. Ellis; J.L. Sweeney. Had the RRC Districts 2 – 6 participants believed that West Texas natural gas sales were relevant to their determination of prices, then price redetermination clauses would have reflected that belief. PX77 ¶¶ 34-35; Testimony of J.L. Sweeney.

71. Six factors (the "Comparability Factors") are given weight for comparability purposes: (i) heating value or Btu content, (ii) the distance from the producing properties to the nearest pipelines, (iii) the volume of gas available for sale, (iv) the deliverability of the wells that produced the gas, (v) the FTP of the gas, and (vi) the hydrogen sulfide content of the gas. *Exxon Corp.*, 45 Fed. Cl. at 621. Exxon's 1976 production of gas well gas and casinghead gas from the 442 properties at issue was comparable for pricing purposes to the gas analyzed in the RMFP Studies in terms of the six Comparability Factors. JX8 ¶ 1.

72. Exxon's 1976 production of gas well gas and casinghead gas was comparable for pricing purposes to the gas analyzed in the Ellis RMFP study. JX8 ¶ 1.

73. The RMFP for the natural gas at issue, adjusted for compression and dehydration costs where appropriate, is $1.15/Mcf. PX79 at 21 and at Ex. 4; Testimony of J.E. Ellis.

74. There are three main sources of information from which to identify raw gas sales

in the market area for 1976: (1) annual reports filed with the FPC by interstate pipeline companies (commonly called Form 2); (2) annual reports filed with the Gas Utilities Division of the Texas Railroad Commission by pipelines doing business in Texas (commonly called GUDs); and (3) contract files from the business records of the largest pipeline companies, which were obtained via extensive discovery in *Exxon I*, *Exxon II*, and in this case. PX79 at 16-18; Testimony of J.E. Ellis.

75. The information included in the Forms 2 and GUD annual reports is widely used in the oil and gas industry and is regarded as a reliable source of information about natural gas markets and prices. The transactional data from the pipeline annual reports were relied upon by both the parties and the courts in *Exxon I* and *Exxon II*. PX79 at 16; Testimony of J.E. Ellis.

76. Contract files can be used to develop information that was not included in the annual reports. This information provides documentation of: (1) the delivery point for sales made under the terms of the contract; (2) the obligation of the seller to dehydrate or compress the gas prior to sale; and (3) the rights and elections of the seller to process natural gas sold under the contract. PX79 at 19; Testimony of J.E. Ellis.

77. Mr. Ellis's initial step in his RMFP computation was to use these sources to identify the raw gas sales in RRC Districts 2 – 6 in 1976. PX79 at 19. He then determined which of these sales qualified for inclusion in the RMFP calculation. PX79 at 20.

78. The court's decision in *Exxon II* provided very detailed guidance as to the methodology for selecting transactions to use in the calculation of the RMFP. The court's guidance included instructions for qualifying transactions based on the location of delivery points and the status of contractually retained rights to process the natural gas before or after delivery,

neither of which had been addressed in *Exxon I* or previous RMFP decisions. Specifically, the court in *Exxon II*, enumerated three ways that a transaction may qualify as a wellhead sale: (1) if a pipeline reported the transaction as an Account 800 wellhead purchase in Form 2 Reports; (2) if a contract specified that the delivery point was at the wellhead or separator outlet of a well; or (3) if the taxpayer can present evidence showing that the delivery point was on the leased property near the well. *Exxon II*, 45 Fed. Cl. at 642; *see also* PX79 at 14; Testimony of J.E. Ellis.

79. In addition, for intrastate transactions in which the seller had a contractually retained right to process the natural gas before or after delivery, the court in *Exxon II* determined that affirmative proof must be presented that the right to process was not exercised during the tax year in question in order for the transaction to be included in the RMFP calculation. *Exxon II*, 45 Fed. Cl. at 695; *see also* PX79 at 14; Testimony of J.E. Ellis. Mr. Ellis applied all four of these criteria in determining which transactions to include in Exxon's RMFP sample for 1976. PX79 at 14; Testimony of J.E. Ellis.

80. The court in *Exxon II* also determined that where the producer dehydrated or compressed its gas before sale, the value that the producer added must be subtracted from the sales price, and only the net price should be used. *Exxon II*, 45 Fed. Cl. at 696. Ronald Platt determined the value added by producer-provided dehydration and compression services, if any, for each of the qualifying transactions in Mr. Ellis's RMFP study. Mr. Platt determined the costs of these services by applying accepted engineering and cost-estimating principles, consulting reliable industry sources and commercial databases, and by using his professional experience. His methods and results are consistent with similar estimations undertaken by the Federal Power Commission and the Federal Energy Regulation Commission. PX82. The parties have

stipulated to the dehydration and compression adjustments. JX9 ¶ 13(a) and Exhibit 1.

81. Using the information Mr. Platt provided and other information from the contract files, Mr. Ellis adjusted the price in each qualifying transaction where required. PX79 at 20. Overall, these cost deductions reduced the RMFP by 5¢/Mcf, from an unadjusted figure of $1.20/Mcf to $1.15/Mcf. PX79 at 21 and at Ex. 4.

82. At the conclusion of this process, 349 transactions remained and thus qualified for inclusion as "wellhead sales" in the calculation of Exxon's RMFP for 1976. JX9 ¶ 12; Testimony of J.E. Ellis. The parties have stipulated that each of these 349 transactions qualifies as a "wellhead sale" for purposes of the RMFP calculation. JX9 ¶ 12.

83. Exxon contends that the relevant market area for purposes of computing its RMFP is the East Texas/Texas Gulf Coast region (the "Exxon Market Area"). Translating the Exxon Market Area into Texas Railroad Commission Districts ("RCDs"), Exxon contends that its relevant market is located within RCDs 2 through 6, with East Texas consisting of RCDs 5 and 6, and the Texas Gulf Coast consisting of RCDs 2, 3 and 4.

84. The remaining seven RCDs within Texas are 1, 7B, 7C, 8, 8A, 9 and 10. The "Permian Basin" consists of RCDs 7C, 8 and 8A. The Texas Gulf Coast consists of RCDs 1 through 4.

85. The $1.15/Mcf RMFP that Mr. Ellis calculated is representative of the volume-weighted average price paid under arm's length contracts in effect in the market area for the sale of unprocessed natural gas at the well in 1976. Testimony of J.E. Ellis. Exxon's natural gas is comparable, for pricing purposes, to the natural gas sold in the RMFP transactions. The $1.15/Mcf RMFP applies throughout RRC Districts 2 – 6. It also applies to natural gas produced

both from gas wells and oil wells (*i.e.*, casinghead gas). PX79 at 1; Testimony of J.E. Ellis.

86. Of the 349 qualifying "wellhead sales" transactions in Mr. Ellis's study, 187 were interstate sales and 162 were intrastate sales. Intrastate sales comprised approximately 60% of the volume for the qualifying transactions, while interstate sales comprised approximately 40% of the volume. The weighted-average price was $1.74 for the intrastate sales and 28¢ for the interstate sales. PX79 at 15, Table 1. Exhibit 4 to Mr. Ellis's report lists all qualifying wellhead sales transactions (intrastate and interstate) and the reasons why each transaction qualifies for inclusion in the RMFP calculation. PX79 at 15.

87. The Court of Federal Claims in *Exxon II* found that, to be truly "representative" of the market, the RMFP calculation, as a general rule, "must include volumes of interstate gas and intrastate gas in relative proportions that are reasonably reflective of the *actual* relative proportions of interstate and intrastate gas sold at the wellhead in that market area." *Exxon II*, 45 Fed. Cl. at 708. Thus, in evaluating the representativeness of a proposed RMFP sample, a court must consider whether the mix of interstate and intrastate wellhead sales in the proffered sample is reasonably comparable to the mix in the relevant market area.

88. Intrastate prices tended to be much higher than interstate prices in 1976, sometimes by a factor of four or more. This fact makes it critical that the RMFP study reflect an appropriate balance of intrastate and interstate transactions. PX80 at 2; Testimony of J.E. Ellis. The use of an incorrect mix of intrastate versus interstate transactions could substantially bias an RMFP calculation so that it fails to be a *representative* market or field price.

89. Mr. Ellis's mix of 60% intrastate sales and 40% interstate sales in his RMFP calculation is a reasonable approximation of the actual mix in the market for 1976. RRC gas

production statistics for 1976 indicate that the actual mix of intrastate and interstate sales in RRC Districts 2 – 6 was approximately 80% intrastate and 20% interstate. PX78 ¶ 76, Table 2 (incorrectly referred to as Table 1 in ¶ 76); PX80 at Ex. 4; Testimony of J.L. Sweeney and J.E. Ellis. Similarly, the actual mix under the severance tax data was approximately 76% intrastate and 24% interstate. PX80 at Ex. 4; Testimony of J.E. Ellis. There is no evidence to suggest that the relative percentages would be appreciably different in 1976 if the RRC and severance tax data were limited to wellhead sales. Testimony of J.E. Ellis. Thus, the mix used by Mr. Ellis tends to overweigh the interstate numbers, leading to a lower RMFP than would be calculated if the actual mix were used, to the detriment of Exxon.

90. Although some wells located in ten counties in RRC 1 were considered by Mr. Pohler in defining Exxon's market area, there was insufficient proof that sales in RRC 1 would materially change the RMFP if the Court confined its consideration to sales in RRC 2-6.

91. During 1976, Exxon sold natural gas produced from the 442 properties under twenty long-term contracts. For the eighteen of those contacts stipulated as fixed contracts, the weighted average price was 22 cents per Mcf.

92. By contract dated September 6, 1963, Exxon entered into a written contract with HL&P by which Exxon agreed to sell and deliver natural gas to HL&P, for twenty years, for use as fuel in several electric generating plants that HL&P operated in the City of Houston, Texas, and the surrounding areas.

93. By a contract amendment dated May 29, 1974 (the "1974 Amendment), Exxon agreed to increase the volume of gas it would make available to satisfy HL&P's immediate fuel requirements, effective June 1, 1974 through December 31, 1978, and to extend the contract's

term past the original expiration, until Exxon's gas supply commitment was discharged.

94. This 1974 Amendment caused the price of natural gas to be sold by Exxon under the contract to increase proportionately with the market price of gas during 1976.

95. The 1974 Amendment provides that "During the period January 1, 1976 through December 31, 1979, there shall be added to the above Contract Prices 20 percent of the difference between the Average Industry Price as hereinafter defined and 24¢ per MMBtu." Thus, during 1976, the price charged to HL&P was not fixed, but rather reflected an increase of 20% of the increase of the Average Industry Price ("AIP") during the period.

96. The AIP was defined in the HL&P Contract as follows:

> The Average Industry Price . . . shall be determined quarterly, from the volume weighted average of the sales price paid for the purchase of gas in the fields or at the tailgate of the gas processing plants in Texas Railroad Commission Districts 2, 3, 4, 5, and 6 (as now constituted) providing for delivery into gas transmission lines for resale as reflected in the "Purchaser's Monthly Gas Tax Reports" . . . filed in the Office of the Controller of the State of Texas and representing the total reported purchases by at least 30 of the largest such purchasers, with the intent that the weighted average price so determined will be representative of the average price being paid by the purchasers of natural gas in the field or at the tailgate of plants in the relevant area. The weighted average price shall be determined ... from "Purchaser's Monthly Gas Tax Reports" filed for the first month of the quarter which immediately precedes the quarter in question.

97. The AIP reflects, on a quarterly basis, the current market price of gas. Because the price of gas charged by Exxon to HLP was increased by 20% of the AIP, the price of gas sold by Exxon under the HL&P Contract also reflects the current market price of gas.

98. The invoices prepared and sent by Exxon to HL&P reflect a single computed price for each MMBtu sold under the contract pursuant to Article III, Section A.

99. The use of the AIP caused the price of gas sold under the HL&P Contract to be

based on the market price of gas. Accordingly, Exxon has failed to meet its burden of proving by clear and convincing evidence that the HL&P Contract was a contract under which the price of gas could not be adjusted to reflect to any extent the increase in liabilities of Exxon for federal income tax by reason of the repeal of percentage depletion. Thus, the HL&P Contract does not qualify as a "fixed contract".

100. The pertinent terms of the HL&P contract are not ambiguous.

101. On April 6, 1962, Exxon and SWEPCO entered into a contract for a twenty-year period whereby Exxon would sell and deliver to SWEPCO natural gas, for use as fuel in three SWEPCO electric generating plants located in northeastern Texas: (I) the Lone Star Station, in Morris County; (ii) the Knox Lee Station, in Gregg County; and (iii) the Wilkes Station, in Marion County.

102. The SWEPCO contract was amended by a letter agreement dated November 16, 1973 (the "1973 Amendment"). The 1973 Amendment provided that

> Effective November 1, 1973, and thereafter during the term of the contract in addition to the price specified in said contract, including the increase herein provided for, Buyer agrees to pay to Seller an amount equal to fifteen and seven-tenths percent (15.7%) of the excess of Seller's Volume Weighted Average Field Price for gas delivered into the Exxon Gas System above such contract price in effect from time to time, such Volume Weighted Average Field Price to be determined as of the first day of each year, and to remain in effect for the purpose of determining such difference for the calendar year thereafter. For purposes of the foregoing, the Volume Weighted Average Field Price shall be the higher of the following:
>
> (a) The weighted average, by volumes, of Seller's Field Prices for gas taken into the Exxon Gas System in Texas Railroad Commission Districts 2, 3, 4, 5, and 6 (as now constituted) as determined from time to time by Seller, or
>
> (b) The volume weighted average price used by Seller in computing royalty

settlements for its gas entering the Exxon Gas System.

103. This provision clearly states that if the "Volume Weighted Average Field Price" of natural gas exceeds the contract price, then the price under the contract will increase. The price, therefore, is not fixed but varies directly with the Volume Weighted Average Field Price. In other words, the 1973 Amendment adjusted the contract price for the sale of natural gas to relate directly to what that amendment refers to as "the Volume Weighted Average Field Price to be determined as of the first day of each year." The 1973 Amendment, therefore, requires that prices for the gas be raised periodically to reflect changes in market prices for pipeline quality natural gas. Accordingly, Exxon has failed to meet its burden of proving by clear and convincing evidence that the SWEPCO contract was a contract under which the price of gas could not be adjusted to reflect to any extent the increase in liabilities of Exxon for federal income tax by reason of the repeal of percentage depletion. Thus, the SWEPCO contract does not qualify as a "fixed contract".

104. The pertinent terms of the SWEPCO contract are not ambiguous.

105. The parties have stipulated that Exxon's percentage depletion allowance, before application of the taxable income limitation, is equal to 22% of the "gross income from the property" (net of royalties) that is attributable to the natural gas sold under fixed contracts. JX12 ¶ 12(a). The parties also have stipulated to the amounts necessary to compute the taxable income limitation for each property and all other elements (except the RMFP) to determine the percentage depletion deduction. JX12 ¶¶ 1-4, 6-9, and at Ex. 1; JX13.

106. Because (1) the RMFP in this case is $1.15/Mcf, and (2) that applies to all of the gas sold under eighteen of the twenty contracts in issue (except HL&P and SWEPCO), Exxon's

1976 total gross income from the 442 properties in issue (net of royalties) is $365,329,531. Accordingly, Plaintiff's percentage depletion deduction before the taxable income limitation is $80,372,727 and Plaintiff's percentage depletion deduction after the taxable income limitation is $80,257,005. Plaintiff's 1976 depletion deduction is increased by $73,686,067 over the amount allowed by the Internal Revenue Service on audit.

107. Any conclusion of law which is more properly deemed a finding of fact is incorporated herein.

CONCLUSIONS OF LAW

1. Jurisdiction is conferred upon this Court by 28 U.S.C. § 1346 (a)(1). Venue is proper in this Court. *Id.* § 1402(a)(2).

2. Taxpayers must prove the amount of any refund they claim. A party who sues the United States for a refund of taxes is said to have a "double burden." The taxpayer must not only prove that the Internal Revenue Service incorrectly determined the taxpayer's tax liability, but it must also establish the correct amount of its tax liability in order to prove that an overpayment has occurred. *Lewis v. Reynolds,* 284 U.S. 281, 283, *modified,* 284 U.S. 599 (1932); *Helvering v. Taylor*, 293 U.S. 507, 514 (1935); *King v. United States*, 641 F.2d 253, 259 (5th Cir. 1981); *Bar L Ranch, Inc. Phinney*, 300 F. Supp. 839, 841 (S.D. Tex. 1969).

3. I.R.C. § 611 provides that:

> [i]n the case of . . . gas wells . . . there shall be allowed as a deduction in computing taxable income a reasonable allowance for depletion . . . according to the peculiar conditions of each case; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary.

4. Under I.R.C. § 613 and Treas. Reg. § 1.613-1(a), a taxpayer's percentage

depletion deduction is computed by multiplying a taxpayer's "gross income from the property," excluding an amount equal to any rents or royalties paid or incurred by the taxpayer in respect of the property, by 22 percent. I.R.C. § 613(a). The percentage depletion deduction is also subject to the taxable income limitation (which is 50 percent of the taxpayer's taxable income from the property computed without regard to allowance for depletion). Treas. Reg. §§ 1.613-1(a), 1.613-5(a). A taxpayer's "taxable income from the property" is generally equal to the taxpayer's "gross income from the property," less certain expenses and deductions. *Id.* The taxable income limitation does not significantly limit Exxon's deduction in this case.

5. I.R.C. § 613A, which was made applicable to tax years ending after December 31, 1974, generally repealed percentage depletion for oil and gas. It provides:

> General Rule.--Except as otherwise provided in this section, the allowance for depletion under section 611 with respect to any oil or gas well shall be computed without regard to section 613.

6. The narrow exceptions to the repeal of percentage depletion under Section 613A are set forth in subsections (b) and (c). Section 613A(b)(1) provides for the fixed contract exception to the repeal of percentage depletion:

> <u>In General</u>.--The allowance for depletion under section 611 shall be computed in accordance with section 613 with respect to
>
> (A) regulated natural gas, and
>
> (B) natural gas sold under a fixed contract . . .
>
> and 22 percent shall be deemed to be specified in subsection (b) of section 613 for purposes of subsection (a) of that section.

Section 613A(b)(3)(A), in turn, defines "natural gas sold under a fixed contract" as follows:

> (A) <u>Natural Gas Sold Under A Fixed Contract</u>–The term "natural

> gas sold under a fixed contract" means domestic natural gas sold by the producer under a contract, in effect on February 1, 1975, and at all times thereafter before such sale, under which the price for such gas cannot be adjusted to reflect to any extent the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion for gas. Price increases after February 1, 1975, shall be presumed to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by clear and convincing evidence.

See also Treas. Reg. § 1.613A-7(d).

7. Exxon was thus entitled to use percentage depletion after 1974 only with respect to sales made pursuant to fixed contracts. Exxon sold gas in 1976 under certain "fixed contracts" within the meaning of Section 613A(b)(3)(A).

8. For integrated producers, the "gross income from the property" is equivalent to the RMFP. Treas. Reg. § 1.613-3(a).

9. Since Exxon was an integrated producer of natural gas in 1976, any depletion deduction must be computed by determining Exxon's "gross income from the property" using an RMFP. Treas. Reg. § 1.613-3(a).

10. The United States is collaterally estopped from arguing that the excess royalty reimbursement clause in the HL&P contract prevents the HL&P contract from qualifying as a fixed contract; however, it is not estopped from arguing that the additional gas clause does so.

11. Exxon has failed to meet its burden of proving by clear and convincing evidence that the HL&P contract was a contract under which the price of gas could not be adjusted to reflect to any extent the increase in liabilities of Exxon for federal income tax by reason of the repeal of percentage depletion. Thus, the HL&P contract does not qualify as a "fixed contract" and Exxon is not entitled to percentage depletion on the natural gas sold under the HL&P

Contract during 1976.

12. The Amended HL&P contract provided that, during 1976, the price charged to HL&P was not fixed, but rather reflected an increase of 20% of the increase of the average industry price ("AIP"). The AIP reflected, on a quarterly basis, the current market price of gas. Because the price of gas charged by Exxon is increased by 20% of the AIP, the price of gas sold by Exxon under the HL&P contract also reflects the current (and increasing) market price of gas, which presumptively takes tax liabilities into account.

13. Accordingly, Exxon has failed to meet its burden of proving by clear and convincing evidence that the HL&P contract was a contract under which the price of gas could not be adjusted to reflect to any extent the increase in liabilities of Exxon for federal income tax by reason of the repeal of percentage depletion. Thus, the HL&P contract does not qualify as a "fixed contract" and therefore cannot be used to calculate percentage depletion.

14. The 1973 Amendment to the SWEPCO contract adjusted the contract price for the sale of natural gas to relate directly to "the Volume Weighted Average Field Price to be determined as of the first day of each year." The 1973 Amendment, thus, requires that prices for the gas be raised periodically to reflect changes in increasing market prices for pipeline quality natural gas. Exxon has failed to meet its burden of proving by clear and convincing evidence that the SWEPCO contract was a contract under which the price of gas could not be adjusted to reflect to any extent the increase in liabilities of Exxon for Federal income tax by reason of the repeal of percentage depletion. Thus, the SWEPCO contract does not qualify as a "fixed contract" and Exxon is not entitled to percentage depletion on the natural gas sold under the SWEPCO contract during 1976.

15. The RMFP for natural gas Exxon produced during 1976 from the 442 properties in issue is $1.15/Mcf, once appropriate adjustments have been made to the sales prices of the sample transactions to reflect the costs of processing and transportation provided by the sellers.

16. Any finding of fact which is more properly considered a conclusion of law is hereby incorporated by reference.

SO ORDERED this 10 day of March, 2003.

BARBARA M.G. LYNN
UNITED STATES DISTRICT JUDGE
NORTHERN DISTRICT OF TEXAS